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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL

Chairman

JIM IRVIN

Commissioner

MARC SPITZER

Commissioner

Arizona Corporation Commission

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IN THE MATTER OF THE GENERIC
PROCEEDINGS CONCERNING ELECTRIC
RESTRUCTURING

DOCKET NO. E-00000A-02-0051

IN THE MATTER OF ARIZONA PUBLIC
SERVICE COMPANY'S REQUEST FOR
VARIANCE OF CERTAIN REQUIREMENTS OF
A.A.C. 4-14-2-1606

DOCKET NO. E-01345A-01-0822

IN THE MATTER OF THE GENERIC
PROCEEDING CONCERNING THE ARIZONA
INDEPENDENT SCHEDULING
ADMINISTRATOR

DOCKET NO. E-00000A-01-0630

IN THE MATTER OF TUCSON ELECTRIC
POWER COMPANY'S APPLICATION FOR A
VARIANCE OF CERTAIN ELECTRIC POWER
COMPETITION RULES COMPLIANCE DATES

ISSUES IN THE MATTER OF TUCSON
ELECTRIC POWER COMPANY'S
APPLICATION FOR A VARIANCE OF
CERTAIN ELECTRIC COMPETITION RULES
COMPLIANCE DATES.

DOCKET NO. E-01933A-02-0069

**INITIAL POST-HEARING BRIEF OF ARIZONA PUBLIC SERVICE COMPANY
ON "TRACK B" ISSUES**

Pursuant to the presiding Administrative Law Judge's ("ALJ") direction, Arizona Public Service Company ("APS" or "Company") hereby submits its Initial Post-Hearing Brief ("Brief") on Track B issues to the Arizona Corporation Commission

1 ("Commission"). This Brief identifies both the issues discussed in the Company's direct
2 and rebuttal testimony and certain matters raised just before or during the Track B
3 evidentiary hearings.

4 SUMMARY OF APS' OVERALL POSITION

5 APS appreciates the effort and endorses the general goals of the Commission's
6 Utilities Division Staff ("Staff") and its consultant in carrying out the Track B process
7 ordered by this Commission. Like Staff, APS supports an effective power procurement
8 process for consumers. After all, consumers must rely on the utility and its regulator to act
9 in the consumers' best interests. APS believes its past efforts to acquire needed and
10 economical resources for its customers at reasonable prices have been extremely
11 successful—producing rate decreases when virtually every other western electric utility
12 was raising prices, often substantially. It further submits that having the flexibility to
13 determine its own procurement needs, as well as the timing and manner of meeting those
14 needs, were and are critical to both the Company's past and future success in such
15 procurement.

16 This Track B process necessarily restricts that flexibility. That is less a criticism
17 than a fact. And whether those restrictions are limited and procedural, or extensive and
18 substantive, is now up to the Commission to determine. APS asks the Commission to keep
19 closely in mind its own findings in Track A about the vagaries of the wholesale market. It
20 should take that same measured and conservative approach to mandating significant
21 changes to what has heretofore worked and worked well in Arizona during one of most
22 difficult times in the history of the electric power industry.

23 APS likewise suggests that this Track B process would warrant and benefit from
24 the Commission taking an active role in reviewing and approving the results of at least
25 this initial foray into a government-mandated, uniform and simultaneous multi-year
26

1 procurement by the state's two largest electric public service corporations. This would add
2 certainty to the process for all concerned and should lower the ultimate cost to Arizona
3 consumers.

4 INTRODUCTION

5 The major unresolved issues in Track B, at least prior to the filing of rebuttal testimony on
6 November 18, 2002, were those set forth at page 34 of the Final Staff Report of October
7 25, 2002 ("Staff Report"). They include¹:

- 8 • Determination of unmet need
- 9 • Role of the Commission, Staff and independent monitor, both during the
- 10 solicitation and in evaluating the reasonableness of the bids
- 11 • Role of the utility in designing and conducting the Track B solicitation
- 12 • "Price to beat"²
- 13 • Standards of conduct for utility-affiliate communications regarding the Track B
- 14 solicitation
- 15 • Least Cost Planning
- 16 • Demand-side management ("DSM") and "Environmental Risk Management"

17 One of the more significant issues arising with the November 18, 2002 filing was
18 Staff's decision to make certain utility-owned and previously rate-based generation
19 "contestable" in Track B despite the absence of any unmet need associated with such
20 generation. (See Staff Exhibit S-5.) The issue of the Commission's treatment of reliability
21 must-run or "RMR" generation will be discussed both under the UNMET NEEDS and
22 TRANSMISSION AND RMR ISSUES Sections of this Brief.

23
24 ¹ APS has rephrased and consolidated certain of the issues listed at page 34 of the Staff Report to
25 better match how it believes these issues were presented during the evidentiary hearing.

26 ² Staff withdrew this recommendation, and APS no longer considers it an issue in the Track B
proceeding.

1 Staff made a similar determination that certain utility purchase power contracts
2 entered into prior to September 1, 2002 would be “contestable.” However, Staff later
3 withdrew that recommendation and adopted the Company’s position. (Tr. vol. V at p. 960
4 [C. Kempley].)

5 In addition, Staff went beyond the language of the Track A order to make economy
6 energy purchases—power purchases made by a utility if and when the cost of power is
7 less than the utility’s incremental cost of generation from existing resources—a part of the
8 Company’s “contestable load,” even though such purchases cannot be considered a part of
9 the Company’s “unmet needs.” This new and significant change to the Staff Report will
10 also be addressed in the UNMET NEEDS discussion below.

11 ISSUE NO. 1 – UNMET NEEDS

12
13 A. *The Company’s calculation of unmet needs is consistent with the language
repeatedly used by the Commission in the Track A Order.*

14 As Mr. Ewen explained in his testimony, APS’ unmet needs were calculated by
15 comparing APS’ October 2002 estimate of expected energy and peak demand
16 requirements over the next ten years with the availability of APS resources to meet those
17 needs. (P. Ewen Direct Test. at p. 2.) That calculation of APS’ unmet needs precisely
18 followed both the Commission’s Decision No. 65154 (September 10, 2002) and the Staff
19 Report’s direction. (P. Ewen Rebuttal Test. at pp. 2–3.) That calculation also is the best
20 current estimate of what APS requires for reliability purposes over the next several years,
21 as evidenced not only by the lack of any credible alternative calculation being put forth
22 for any of the specific elements of the APS calculation, but also the fact that Tucson
23 Electric Power Company (“TEP”) calculated its Track B unmet needs in the same manner.
24 (*Id.* at p. 3.)

25 In Decision No. 65154, the Commission ordered APS to “acquire, at a minimum,
26 any required power that cannot be produced from its own existing assets, through the

1 competitive procurement process as developed in the Track B proceeding.” (Decision No.
2 65154 at pp. 23, 30 and 33, emphasis added.) As can be seen by the citation, the
3 Commission said this not once, but three separate times in its Decision. The Commission
4 also explained and limited its qualifier “at a minimum” to mean that APS “may decide to
5 retire or replace inefficient, uneconomic, environmentally undesirable plants,” an action
6 that would necessarily result in an increase in unmet needs. (Decision No. 65154, fn. 8 at
7 p. 23). The Commission further clarified that it was ordering this approach to “encourage
8 a *phase-in* to competition” because “the wholesale market is not currently workably
9 competitive [and] reliance on that market without recognizing its current uncertainty and
10 limitations will not result in just and reasonable rates for captive customers.” (Decision
11 No. 65154 at pp. 29-30, emphasis added.) All of these statements clearly indicate that the
12 Commission wanted to move cautiously and did not intend for APS to subject more of its
13 energy and capacity needs to the procurement process than was reasonable to begin the
14 transition to competition.

15 Staff itself provided clarification of its interpretation of Decision No. 65154 in the
16 Staff Report:

17 To the extent that a utility has load requirements, capacity or
18 energy, not served by generating capacity owned by the utility
19 or through existing contracts for capacity or energy or from
20 sources which the utility must purchase power as a result of
law or regulation, that unmet need will be acquired through a
competitive solicitation.

21 (Staff Report at p. 4.)

22 For 2003, the solicitation will be for all load and energy
23 requirements not served by generation owned by the utility
24 and included in the utility’s rate base as of September 1, 2002,
except to the extent that such generation is providing RMR
25 service during RMR hours or by power supplied pursuant to
FERC or Commission approved contracts with affiliated and
26 non-affiliated suppliers entered into prior to September 1,
2002. . . . Any generation capacity owned by a utility that has
not been included in the utility’s rate base may be bid by the

1 utility in the initial solicitation on the same terms and
2 conditions as all other bidders, including affiliated bidders.

3 (Staff Report at p. 6.)

4 These statements by Staff support the conclusions reached by the Commission in
5 Decision No. 65154. The Staff proposal, first raised during the hearing, to add the term
6 "economically" in several places in the Staff Report is not justified in light of the specific
7 language to the contrary in Decision No. 65154. It also ignores current market
8 uncertainties and would subject APS to more financial risk instead of less. This is most
9 clearly evidenced by Staff's and the Commission's own conclusion that the wholesale
10 electric market is not workably competitive, even "dysfunctional." (E. Johnson Direct
11 Test. at p. 3; Tr. vol. I at pp. 112, 117-118 [E. Johnson].)

12 Following the direction provided by the Commission and Staff, as discussed above,
13 APS calculated the number of hours for which it will require additional supply beyond
14 that which APS' own resources and firm contracts can provide. As would be expected for
15 a utility with a system load factor in the low 50% range, the unmet capacity needs far
16 exceed the unmet energy needs. (P. Ewen Direct Test. at p. 2.) It is undisputed that APS
17 only needs capacity or low capacity factor products and generally in the third quarter of
18 the year. Although some of the merchant intervenors argued, at least originally, that the
19 APS' statement of unmet needs might not be appropriate in this or that respect, they
20 offered no credible alternative calculations for any of the specific elements of the APS
21 calculation.

22 1. APS Load and Energy Forecasts

23 Although two of the merchant generator witnesses, Thomas Broderick and Dr.
24 Craig Roach, assert generally that the APS load and energy forecasts reflect a "persistent
25 underestimation" of load, it is noteworthy that neither they nor any other parties to this
26 proceeding offered any specific criticisms of the methods or assumptions APS used in

1 preparing its load forecast. (See, e.g., Tr. vol. V at pp. 867-868 [C. Roach].) Indeed, as
2 demonstrated in more detail in Mr. Ewen's Rebuttal Testimony, APS' load forecast has
3 been remarkably accurate, particularly in the last few years, when compared to other
4 relevant industry forecasts. (See P. Ewen Rebuttal Testimony at pp. 7-8, and also at
5 Schedule PME-1R.) This accuracy is not surprising—APS has every incentive to be as
6 accurate as possible in its forecasting efforts, while the merchant generators clearly have
7 an incentive for advocating the use of a higher than required retail sales forecast. APS'
8 load forecast should be accepted, as it has been by Staff (Staff Exh. S-5), as the starting
9 point for the solicitation process.

10 **2. Specific Adjustments Proposed to the APS Calculation** 11 **of Unmet Need**

12 During the hearing, several adjustments to the APS forecast and calculation of
13 unmet needs were proposed or discussed. When examined more closely, however, it
14 becomes clear that APS' calculation of unmet needs was appropriate:

- 15 • Citizens, TOUA and Wickenburg contracts: As was demonstrated during
16 the hearing, these three contracts should not be added to or considered as
17 APS load. Citizens and TOUA are served entirely by Pinnacle West
18 Marketing and Trading ("M&T") from M&T's non-APS resources and
19 are not APS contracts. (P. Ewen Rebuttal Test. at p. 9.) While the 5 MW
20 Wickenburg agreement is an APS contract, it is a market rate tariff
21 contract for which non-dedicated resources are used (it is an incremental
22 opportunity sale). Thus, it does not warrant the same level of treatment as
23 the cost of service based contracts that the Company has included in APS
24 load. (Tr. vol. III at p. 531 [P. Ewen]; P. Ewen Direct Test. at Schedule
25 PME-1.) Even Mr. Broderick had abandoned this adjustment by the
26 conclusion of his oral testimony. (Tr. vol. V at p. 933 [T. Broderick].)

- 1 • Summer 2003 Contracts: As discussed in Mr. Ewen's rebuttal testimony
2 and acknowledged by Staff during the hearing, Mr. Broderick's proposal
3 that four APS purchase power contracts be treated as M&T contracts,
4 thereby arbitrarily reducing the existing APS resources available to APS
5 to meet demand and energy needs, should be rejected. Each of the
6 contracts at issue is an APS firm contract obtained from non-affiliates
7 prior to September 1, 2002 to meet and serve APS' retail customer load
8 in the summer of 2003. (P. Ewen Rebuttal Test. at p. 10 and at Schedule
9 PME-2R.) Three of the agreements clearly were entered into by APS in
10 2000. Even the one contract (with Morgan Stanley) signed by M&T on
11 APS' behalf was a replacement contract in 2001 for an Enron agreement
12 with APS that was contemporaneous to the other three contracts. (*Id.*; see
13 also Tr. vol. V at p. 947 [T. Broderick].) Thus, those contracts should not
14 be included in the calculation of contestable energy. (Tr. vol. V at p. 960
15 [C. Kempley]; *see also* Tr. vol. II at p. 360 [A. Kessler]; and Tr. vol. III
16 at p. 507 [S. Wheeler].)
- 17 • Non-APS RMR Needs: The parties agreed during the hearing that the
18 APS estimate of non-APS RMR needs will be used as a placeholder
19 pending the completion of the RMR study. (P. Ewen Direct Test. at p.
20 21.) That study will clarify a number of aspects relating to the calculation
21 of RMR needs, including deliverability to both the Phoenix and Yuma
22 load pockets. Once that study is completed, APS believes that the non-
23 APS RMR needs should be addressed separately in the overall
24 procurement process due to the unique delivery issues associated with
25 such needs. (*Id.* at p. 20; Tr. vol. III at p. 504 [S. Wheeler].)
- 26

- 1 • APS RMR Resources: APS opposes any inclusion of the APS-owned
2 RMR resources in the estimate of contestable load. Such inclusion is
3 contrary to the Track A order, contrary to the Staff Report, contrary to
4 Staff's position in Track A, and wholly unsupported by any articulated
5 rationale. Additionally, making those APS resources "contestable" fails
6 to consider the range of system benefits they provide beyond their ability
7 to provide RMR service (Tr. vol. III at pp. 504-505 [S. Wheeler]) and
8 will add unnecessary complexity and cost to the procurement process.
9 APS will address this issue in more detail below due to its fundamental
10 importance.
- 11 • Environmental Portfolio Standard: APS' calculation of its Environmental
12 Portfolio Standard ("EPS") requirements was not disputed during the
13 hearing. APS has proposed and Staff has agreed that generators may
14 submit proposals to meet APS' EPS needs as part of the general
15 procurement process. (Tr. vol. III at p. 687 [P. Ewen] and 698 [S.
16 Wheeler].) In addition, APS currently has outstanding a renewables RFP.
17 APS does not believe, however, that it should be required to include its
18 EPS requirement in the calculation of unmet needs (Tr. vol. III at p. 691
19 [P. Ewen] and at p. 699 [S. Wheeler].) Nor does APS believe that
20 renewable proposals should receive any preference in the general
21 procurement process.

22 ***B. The Commission should not require APS to make APS-supplied RMR resources***
23 ***contestable***

24 The record does not support making APS-supplied RMR "contestable" in the
25 competitive solicitation. There is no precedent of which APS is aware for bidding out
26 company-owned RMR capacity, and Staff witnesses could point to no example that

1 supported their proposal to make such capacity contestable. (Tr. vol. III at pp. 504-05 [S.
2 Wheeler]; Tr. vol. II at p. 352 [J. Smith].) Moreover, making APS-supplied RMR capacity
3 contestable is contrary to both the Track A order (which specifically referred to needs that
4 could not be met by the utility) and to Staff's earlier position that the Commission should
5 order APS to retain its generation, and most specifically its RMR generation, which was
6 to be retained under any circumstances. (Tr. vol. II at p. 344 [J. Smith]; Tr. vol. III at pp.
7 429-30 [D. Hutchins]; and Tr. vol. VII at p. 1584 of the Track A proceeding, of which the
8 ALJ took official notice in Tr. vol. II at p. 337.) Staff acknowledged that the pricing
9 protocols for such an RMR solicitation are not known—could APS bid its own units at
10 cost or market, and what is “market” when dealing with RMR generation? (Tr. vol. II at
11 pp. 350-52 [J. Smith].) The universe of potential bidders is certainly more limited than for
12 the general solicitation. (Tr. vol. II at p. 348 [J. Smith].) It could require amendments to
13 the soliciting utility's Open Access Transmission Tariff. (Tr. vol. III at p. 431 [D.
14 Hutchens].) It also runs the risk of ignoring benefits offered by APS-owned RMR units,
15 such as local spinning reserve and voltage support. (Tr. vol. III at p. 505 [S. Wheeler].)
16 Further, the horizon for the first solicitation is unlikely to provide much in the way of
17 either new local generation or significant transmission projects, either of which would
18 require years to complete and could probably not be fully relied upon until closer to an in-
19 service date. (See Tr. vol. II at pp. 377-80 [J. Smith]).

20 Given the already complex nature of the current solicitation and the lack of
21 precedent around the country for such a proposal, including APS-supplied RMR in the
22 competitive solicitation is an experiment that is best left for another day and another
23 proceeding. Moreover, APS has agreed to competitively bid for non-APS supplied RMR
24 requirements, which will allow for a market test as suggested by Staff and some of the
25 intervenors. (T. Carlson Direct Test. at p. 4.)

26

1 ***C. The financial community has likewise interpreted the Track A order as***
2 ***preserving traditional cost-of-service regulation for the Company's existing***
3 ***utility-owned generation resources.***

4 Although the likelihood of receiving a competitive bid for the handful of RMR
5 hours served by APS-owned generation resources is slight, the continued non-
6 contestability of existing APS generation has important symbolic significance in the
7 financial community. (Tr. vol. III at pp. 507-509 [S. Wheeler]; and also at pp. 434-435
8 [D. Hutchens].) As noted in the Standard & Poor's report attached to Chairman Mundell's
9 letter of October 18, 2002 in Docket No. E-01345A-02-0707, the most (perhaps only)
10 positive feature of Decision No. 65154 from the perspective of the ratings agencies was
11 the continued rate base cost-of-service regulation of existing APS generation, including
12 that used to provide RMR service to the Company's customers. (*Id.*) Such an
13 interpretation was consistent with Staff's position in Track A, as evidenced by the
14 Supplemental Testimony of Staff witness Matthew Rowell. (Official notice taken in Tr.
15 vol. II at p. 344; see also pp. 341-343 [J. Smith].) Staff has articulated no rationale for its
16 sudden and belated change of position—a fact that would make its adoption all the more
17 troubling for the financial community.

18 ***D. APS should not be required to acquire economy energy through the Track B***
19 ***process.***

20 Economy energy is energy that is purchased either in real time or a relatively short
21 period prior to its intended use. Such transactions are entered into when it is cheaper to
22 buy energy in the market, even if it carries with it some capacity costs, than to continue to
23 operate APS generation or to begin operating what was a previously idle APS resource.
24 Because this self-generation option must necessarily exist to support an economy
25 purchase, economy energy cannot, by its very definition, be "required power that cannot
26 be produced from its [APS'] own existing assets." (See Decision No. 65154 at pp. 23, 30
and 33; emphasis added.) Neither can it represent APS needs that were heretofore

1 produced by generating units that APS "may decide to retire or replace" as "inefficient,
2 uneconomic, environmentally undesirable plants." (*Id.* at p. 24.) Such plants cannot be an
3 alternative to purchase power, economic or otherwise, if they are "retired or replaced,"
4 and APS has already accounted for such retirements and replacements in its calculation of
5 unmet need. (P. Ewen Direct Testimony at p. 18; P. Ewen Rebuttal Test. at p. 3.)

6 In fact, Staff's decision to recommend the pre-bidding of economy energy through
7 some formal multi-year RFP or auction process is unprecedented anywhere in the country.
8 (Tr. vol. III at pp. 505-506 [S. Wheeler]; and also Tr. vol. II at p. 321 [A. Kessler].) It is
9 inconsistent with Staff's position in Track A. (Tr. vol. II at p. 325 [E. Johnson].) And it is
10 bad for APS customers because it makes it harder for APS to align economy purchases
11 with available resources, while at the same time managing and mitigating risk. (T. Carlson
12 Rebuttal Test. at pp. 6-9.)

13 In its rebuttal case, APS proposed a compromise that both increases the amount of
14 energy bid as a result of Track B and allows APS some of its current flexibility in the
15 purchase of economy energy. This compromise proposal involved bidding 50% of
16 forecast estimated economy energy needs for the upcoming 12 months through a series of
17 quarterly auctions held on the first business day of the month preceding each quarter. The
18 balance of APS' economy and other short-term energy needs would, with some
19 exceptions required to maintain reliability, be acquired from non-affiliates or through
20 "blind" procurements using electronic trading platforms or independent brokers. (T.
21 Carlson Rebuttal Test. at pp. 10-13.) This experimental procurement program would only
22 be continued after 2004 by express order of the Commission because of the real potential
23 of higher costs to consumers caused by this departure from the Company's normal
24 procurement practices. (*Id.*)

1 *E. The amount of capacity and energy bid affects both the perception and the reality*
2 *of the potential harm from the Track B bidding process.*

3 TEP witness David Hutchens noted that the amount TEP was required to bid, even
4 though it would be under no obligation to accept any of such bids, was negatively
5 perceived in the financial community as adding to the utility's risk. (Tr. vol. III at p.434.)
6 This was especially true if the utility lacked a rate adjustment mechanism covering the
7 costs of purchased power. (*Id.*) APS witness Steven Wheeler not only agreed with Mr.
8 Hutchens, but went on to add:

9 And that would also be the case with respect to the higher
10 numbers in Staff's Exhibit S-5 creating a heightened and perhaps
11 unrealistic expectation that bids will or should be accepted for all of
12 such amounts, even though accepting such bids would not be in the
13 customers' best interest.

14 I understand Staff has said we have the discretion to reject
15 bids, but I also know that if heightened expectations are frustrated,
16 there is an additional potential for hearings and litigation, also which
17 would not be positive.

18 Therefore, and with respect to this issue, and particularly given
19 the absence of any showing in this proceeding, at least any showing
20 that I'm aware of, that suggests that this [Track B] procurement
21 process will indeed produce results better than APS' existing
22 procurement program, I would urge the Commission and I would urge
23 the Staff to be cautious, to be conservative, and to be realistic in
24 establishing the parameters for bid amounts.

25 (Tr. vol. III at p. 509 [S. Wheeler]; *see also* Tr. vol. III at p. 574 [S. Wheeler].) And a
26 recent Fitch publication dated December 17, 2002 likewise cited the uncertainty over
Track B procurement issues as a negative factor facing APS. *See* Appendix A attached
hereto.

22 **ISSUE NO. 2 – ROLES OF THE COMMISSION, COMMISSION STAFF**
23 **AND THE INDEPENDENT MONITOR**

24 *A. The Commission should explicitly approve both the process and the result of a*
25 *procurement process it has mandated.*
26

1 APS and several of the merchant intervenors have testified that express
2 Commission approval of the Track B procurement process (and of the resulting power
3 purchase agreements) will benefit customers. (Tr. vol. III at p. 510 [S. Wheeler]; Tr. vol.
4 IV at p. 789-790 [C. Kebler]; and Tr. vol. V at p. 866 [C. Roach]; see also C. Kebler
5 Rebuttal Test. at p. 2.) It will benefit them by reducing or eliminating any regulatory risk
6 premium that would otherwise attach to the bids offered in Track B. (*Id.*) It will also give
7 them confidence in the process itself. (Tr. vol. V at p. 866 [C. Roach].)

8 Such Commission approval and its corresponding assurance of cost recovery on the
9 part of the utility are especially appropriate in this proceeding. The Commission is
10 mandating many new aspects of this Track B purchase power acquisition process. It will
11 be a process other than that believed to be the most prudent by Company management.
12 (Tr. vol. III at pp. 511-513 [S. Wheeler]). And it is not the process that APS has used very
13 successfully during the most turbulent time in the history of the electric power industry in
14 this country. (T. Carlson Rebuttal Test. at pp. 4-5.) Indeed, one of Staff witnesses in the
15 Track A proceeding indicated that subsequent Commission disallowance of what were in
16 effect Commission-mandated costs would be, in his words, "disingenuous." (Track A Tr.
17 vol. VII at p. 1577 [M. Rowell].)

18 ***B. Staff's role should first be that of an active partner and participant in the Track***
19 ***B procurement and secondly as advisor to the Commission in the approval***
process.

20 Staff has an absolutely vital role in the Track B process. It was Staff that brought
21 about the consensus that emerged from the workshops. (Staff Report at pp. 31-33.) It was
22 Staff that has determined the timeline and sequence of events in Track B. (Staff Report at
23 pp. 27-29.) And Staff has asked the Commission to determine what products APS must
24 include in the Track B solicitation (A. Kessler Rebuttal Test. at p. 9), for what period the
25 solicitation should cover (Staff Report at p. 35), and how much APS should be required to
26 solicit for each of those years (Staff Exh. S-5). Having taken such an activist role to date,

1 it is reasonable for Staff to continue as a full partner in the actual Track B solicitation and
2 to timely advise the Commission as to which contracts should or should not be approved
3 by the Commission for subsequent full cost recovery. (Tr. vol. III at pp. 510-513 [S.
4 Wheeler] and pp. 551-552 [S. Wheeler].)

5 Indeed, even if there is no formal Commission approval process, the parties to the
6 Track B solicitation, both buyers and sellers, would no doubt take considerable comfort in
7 what would be a form of de facto prudence review of the solicitation and its outcome. (C.
8 Roach Rebuttal Test. at pp. 9-10.) If no such prudence review is undertaken by Staff
9 contemporaneously with the Track B procurement, there is an even more compelling case
10 for direct Commission involvement and approval as was discussed in the previous
11 subsection of the Company's brief.

12 ***C. The independent monitor's role should be that of advisor to Staff rather than***
13 ***that of a substantive decision-maker.***

14 The role of the independent monitor described in the Staff Report at pages 9
15 through 11 strikes APS as appropriate so long as Commission Staff and the independent
16 monitor work closely with the utility to contemporaneously identify and correct potential
17 problems with the Company's Track B solicitation. (S. Wheeler Direct Test. at p. 6.) But
18 APS would suggest that it would not be appropriate for Staff and the monitor to criticize
19 the Company for alleged deficiencies in the procurement process that had not been raised
20 initially with APS while there was still time and opportunity to address them. (Tr. vol. III
21 at p. 513 [S. Wheeler].)

22 APS is opposed to making the monitor a substitute for either the Commission or
23 Staff. The monitor should not be able to "vote" on which contracts are to be awarded by
24 APS nor should it be the final say on whether or not the Track B solicitation was
25 conducted in an appropriate manner. Although the Commission should afford great weight
26 to the unchallenged conclusions of the monitor in its review of the Track B process, the

1 Commission must accept responsibility for the ultimate approval of the Track B
2 solicitation and the results thereof.

3
4 **ISSUE NO. 3 – AFFILIATE RELATIONS**

5 ***A. APS already has submitted a proposed expanded Code of Conduct in response to***
6 ***the Track A order, and it is presently subject to a FERC Code of Conduct and***
7 ***FERC Standards of Conduct, in addition to this state's comprehensive set of***
8 ***general affiliate regulations.***

9 APS presently has a Code of Conduct covering itself and Competitive Electric
10 Affiliates that was approved by the Commission in Decision No. 62416 (April 3, 2000), as
11 well as Policies & Procedures ("P&P") to effectuate that Code. This existing APS Code of
12 Conduct, which is required by A.A.C. R14-2-1616, addresses each of the following areas:

- 13 • cross-subsidization
- 14 • access to confidential information
- 15 • joint employment
- 16 • preferential treatment of affiliates
- 17 • inference of preferential service to affiliates
- 18 • inter-affiliate transactions
- 19 • joint advertising, sales, and marketing
- 20 • use of the APS name and logo
- 21 • complaint procedures

22 Other issues, such as access to proprietary customer information and affiliate financing
23 arrangements, are also subject to specific existing Commission regulations. See A.A.C.
24 R14-2-1612 (E) and A.A.C. R14-2-804.

25 Both the Code itself and the P&P were negotiated between the Company and
26 Staff, and in the over two years since their implementation, APS has not been so much as
accused of a violation of either. Even in California, where market abuse is alleged to have

1 become the norm and not the exception, APS refused to compromise business integrity for
2 unjust profit.

3 As a result of the Track A order, APS submitted a revised Code of Conduct on
4 November 12, 2002. Pursuant to the terms of Decision No. 65154, a separate hearing will
5 be held to consider this revised Code of Conduct. (See Decision No. 65154 at p. 25.)

6 The Commission has also had general rules and regulations concerning affiliate
7 transactions with public service corporations since the early 1990s. See A.A.C. R14-2-
8 801, *et seq.* These rules cover a wide array of transactions and have extensive reporting
9 requirements. APS is one of the few Arizona Class A utilities that has not received a
10 waiver of the affiliate rules and has always taken a conservative view in complying with
11 such regulations.

12 APS is further subject to FERC imposed Standards of Conduct that prevent the
13 subsidization of generation by transmission and prevent APS from granting preferential
14 access to either its physical transmission system or to information concerning such
15 system. There is also a FERC code of conduct dealing with specific affiliate transactions,
16 although APS has been granted a very limited waiver of such code during the Company's
17 present retail rate moratorium and in consideration of the Commission's Electric
18 Competition Rules.

19 APS makes these observations to emphasize to the Commission that the Company
20 is already subject to considerable regulation in the field of affiliate relations. (Tr. vol. III
21 at p. 536 [S. Wheeler].) Moreover, APS is taking proactive steps to more carefully
22 delineate regulated from non-regulated functions within the Pinnacle West companies.

23 ***B. APS is presently developing Standards of Conduct for the Track B procurement***
24 ***consistent with the recommendation contained within the Staff Report even***
though the Commission has not adopted the Staff f Report or any part thereof.

25 Under the Staff Report's recommendation, APS must submit Standards of Conduct
26 by the end of January 2003. (Staff Report at p. 38.) APS is attempting to accelerate that

1 process even though it is unlikely that there will be a final Commission decision adopting
2 or rejecting that portion of the Staff Report until approximately that same time. However,
3 given the already stringent regulation of the Company's affiliate relations and the
4 anticipated participation in the Track B solicitation of the monitor and Commission Staff,
5 both of which will serve to alleviate merchant concerns, APS would not hold up an
6 already tardy (for 2003) solicitation until there is complete agreement over these
7 Standards. Such agreement is not likely given the position of the merchant intervenors in
8 this proceeding.

9 ISSUE NO. 4 – PROCUREMENT ISSUES

10 **A. *APS should have the discretion to determine the specific energy products***
11 ***required to satisfy its unmet needs and the specific manner of their Track B***
12 ***procurement.***

13 Page 16 of the Staff Report states that “[E]ach utility shall determine the specific
14 products it will contract for in order to maintain an appropriately structured power supply
15 portfolio.” APS strongly agrees with that statement and would hope that Staff's apparent
16 retreat from this position (A. Kessler Rebuttal Test. at p. 9.) is just that—more apparent
17 than actual. To that point, APS witness Thomas J. Carlson has identified three basic
18 electric product groups for which it would solicit bids: (1) capacity only; (2) capacity with
19 firm energy; and (3) physical call options. (T. Carlson Direct Test. at pp. 7-8.) Mr.
20 Carlson also explained how combinations of these products would give him dispatchable
21 energy, albeit perhaps at a premium. (T. Carlson Rebuttal Test. at p. 14.). And it would
22 not preclude unit contingent bids of the type advocated by Dr. Roach. (*Id.* at p. 17.)

23 **B. *APS should have the discretion to use an RFP, an auction, or any combination***
24 ***of these procurement vehicles in conducting the Track B solicitation, and most***
importantly, it must retain the power to say “no” to any or all the bids received as
a result of Track B.

25 The Staff Report again would grant such flexibility. (Staff Report at pp. 22 and 24.)
26 Staff witnesses repeated that position during cross-examination. (Tr. vol. I at pp. 105 [E.

1 Johnson], 130 and 156 [A. Kessler].) Only merchant intervenor witness Curtis Kebler
2 appeared to take issue with this position as to the procurement method. (C. Kebler Direct
3 Test. at pp. 3-8; C. Kebler Rebuttal Test. at p. 6.) However, APS fully explained its
4 reasons for adopting both an RFP process for at least the initial Track B solicitation while
5 retaining an auction format for potential quarterly solicitations of economy energy or
6 subsequent solicitations of unmet needs. (T. Carlson Direct Test. at pp. 5-7; and T.
7 Carlson Rebuttal Test. at pp. 10-13.) And no witness directly disputed the Company's
8 power to reject bids, which power to say "no" is essential to a prudent procurement
9 process. (T. Carlson Direct Test. at pp. 15-16.)

10 **C. *APS should have discretion in determining the timing of secondary solicitations***
11 ***if the Track B solicitation does not result in contracts for all of the Company's***
unmet needs.

12 The Staff Report is silent about secondary solicitations, and Staff was somewhat
13 unclear on this point during cross-examination. (Tr. vol. II at pp. 364-366 [A. Kessler].)
14 About the closest Staff came to addressing this issue is its discussion at page 4 of the Staff
15 Report: "Short-term power and daily, weekly or monthly power acquired to meet
16 unplanned needs, would continue to be purchased in the normal course of business as it is
17 today." (Emphasis added.) APS endorses this concept and asks that it be explicitly
18 adopted for all secondary solicitations outside the formal Track B process.

19 Indeed, given the delay in Track B from its originally scheduled completion date in
20 October 2002, APS has already expressed its concerns about obtaining its third quarter of
21 2003 reliability needs. (T. Carlson Direct Test. at pp. 14-15.) And it has already begun the
22 process of implementing appropriate hedge strategies. (*Id.*)

23 **D. *APS should have the discretion to establish the term for which it will solicit***
24 ***unmet needs through the Track B process and the length of contracts used for***
such purpose.

25 The former of these two related aspects of power procurement is granted by the
26 Staff Report on the high side (i.e., there is no maximum term), but the Staff Report would

1 require the Track B solicitation to encompass at least four years. (Staff Report at p. 35.)
2 Although this does match the Company's own selected solicitation period (T. Carlson
3 Direct Test. at p. 3), APS opposes mandatory solicitation terms whether on the high side
4 (see T. Carlson Rebuttal Test. at p. 20) or the low side.

5 On the issue of contract length, APS witness Carlson explained the present
6 difficulties with long-term agreements. (T. Carlson Direct Test. at p. 9.) This does not
7 mean that APS will not consider longer-term proposals, but such proposals should be
8 prepared to address and satisfy these legitimate concerns of the Company. (T. Carlson
9 Rebuttal Test. at pp. 18-20.)

10 **ISSUE NO. 5 – TRANSMISSION AND RMR ISSUES**

11 ***A. APS' RMR requirements for the Valley and Yuma.***

12 As is common with most metropolitan areas in the Western United States (T. Glock
13 Rebuttal Test. at p. 5; Tr. vol. IV at p. 811-12 [W. Kendall]), APS has some RMR
14 generation requirements when transmission import into its service area becomes
15 constrained. For APS, there are RMR requirements in both its Phoenix and Yuma service
16 areas, but the need for RMR is primarily limited to the summer during peak hours. Most
17 of APS' RMR requirements can be accommodated by APS-owned generation (Ocotillo,
18 APS West Phoenix, and Yucca), but there will be some limited requirements for non-APS
19 RMR capacity and energy. (See P. Ewen Direct Test. at p. 20 and Schedule PME-1; P.
20 Ewen Rebuttal Test. at p. 11.) And, APS' specific RMR requirements in Phoenix and
21 Yuma will change (perhaps significantly) over time based both on transmission system
22 improvements and additions and energy and demand growth inside the constraint. (T.
23 Glock Rebuttal Test. at p. 4.)

24 For APS, the Phoenix and Yuma service areas are somewhat different in terms of
25 specific RMR requirements and the analysis of such requirements. In Phoenix, there are
26

1 three primary transmission owners—APS, Salt River Project (“SRP”) and the Western
2 Area Power Administration (“WAPA”). APS and SRP, which each serve load in the
3 Valley, jointly administer the need for RMR generation in this area. There are also only
4 three current suppliers of generation within the Valley transmission constraint—APS,
5 SRP and PWEC. (Tr. vol. II at p. 348 [J. Smith].) However, like APS, SRP’s local
6 generation may be committed to meeting SRP load when RMR generation is needed. (*Id.*)
7 In Yuma, APS is the only owner of transmission within the Yuma area, but WAPA
8 interconnects there. Also, there are two non-affiliated electric generators (the Yuma
9 Cogeneration Associates unit and an Imperial Irrigation District unit) located within the
10 Yuma constraint that are selling to California, which frees up additional transmission
11 scheduling capability into the Yuma area without any additional cost to APS or its
12 customers. (Tr. vol. III at p. 716 [T. Glock]).

13 ***B. The Commission should reject both calls to ignore RMR or to overstate the RMR***
14 ***situation. Rather the Commission should defer to the Commission-ordered RMR***
study currently underway.

15 Some of the merchant generators have asked the Commission to ignore RMR
16 issues in a manner that could force APS and its customers to buy generation that cannot be
17 delivered to APS load. (*See, e.g.,* T. Broderick Direct Test. at p. 16-17.) It is, however,
18 inappropriate to ignore deliverability and the Staff proposal specifically requires a
19 deliverability analysis as part of the evaluation of competitive bids. (*See* T. Glock
20 Rebuttal Test. at pp. 2-3; Tr. vol. II at pp. 355-56 [J. Smith].) Similarly, those merchant
21 generators that criticize the limited need for RMR to justify an “RMR premium” for their
22 power plants overstate the practical concerns on this issue. In Yuma, for example, there is
23 currently significant operational flexibility to reliably meet load and there are numerous
24 future options for increasing that load serving capability such that an “RMR premium” is
25 simply not warranted. (T. Glock Rebuttal Test. at pp. 5-6.) For example, the out-of-area
26 sales from local generators today allows APS to schedule additional generation into Yuma

1 without requiring APS customers to pay for more transmission lines or any sort of
2 premium for RMR generation. (Tr. vol. III at pp. 716-17 [T. Glock].) Similarly, APS
3 believes that the timing and nature of future transmission projects that may alleviate RMR
4 should not be assumed until closer to the actual in-service dates for those projects. (T.
5 Glock Rebuttal Test. at pp. 4-5.)

6 The issues surrounding RMR for Yuma and Phoenix, including APS' assessment
7 of potential solutions, will be documented in the RMR Studies that are underway pursuant
8 to the Commission's Biennial Transmission Assessment. (*Id.* at p. 4; Tr. vol. II at pp. 354-
9 56 [J. Smith].) Those studies, which will be completed by January 31, 2003, should
10 quantify RMR issues and will be used by APS in developing its solicitation and evaluating
11 its needs. The Commission should therefore defer to those studies to address specific
12 RMR needs and requirements.

13
14 **ISSUE NO. 6 – LEAST COST PLANNING, DSM, EPS**
15 **AND ENVIRONMENTAL RISK MANAGEMENT**

16 APS has long supported cost-effective DSM. However, there is presently no
17 funding allocated for DSM. Nor is there any regulatory process in place for evaluating the
18 effectiveness of DSM programs. (S. Wheeler Rebuttal Test. at p. 9.)

19 Least cost planning has been dormant for a number of years in Arizona. It would
20 take significant time to reactivate and modernize that process even if Arizona is
21 determined to return to traditional regulation. (*Id.* at pp. 8-9.)

22 The Environmental Portfolio Standard ("EPS") was listed by the Staff Report as a
23 consensus issue. APS is satisfied with that consensus position. (Staff Report at p. 32.)

24 Environmental risk management" is an issue reminiscent of the "environmental
25 externalities" debated by the Commission in the early 1990s. As with the prior issues
26 discussed in this Section of APS' Brief, the present record is insufficient to warrant
adoption of the recommendations of Land and Water Fund witness Dr. David Berry,

1 Wellton-Mohawk witness Robert Kendall or Residential Utility Consumer Office witness
2 Dr. Richard Rosen on these specific issues. (*Id.* at p. 11.) If the Commission wishes to
3 consider the issues raised by these witnesses, the Company would not oppose further
4 workshops to address them.

5 CONCLUSION

6 APS has calculated its unmet needs in strict conformance with Decision No. 65154.
7 Deviation from the requirements of that Decision is not only legally inappropriate, given
8 the lack of compliance with A.R.S. § 40-252, it would have an unsettling impact on the
9 financial community, which already is closely watching APS and this Commission. It is
10 also likely to lead to higher costs for consumers and unintended, but nevertheless adverse
11 environmental impacts, especially in metro-Phoenix, should it lead to the construction of
12 redundant generating capacity within these areas or the over-construction of new
13 transmission facilities.

14 The proper roles of the Commission, Staff and the monitor in the Track B process
15 are a direct result of the origins of this Track B proceeding, which is nothing less than a
16 regulatory mandate. The Commission should, with the aid and advice of Staff and the
17 monitor, make an expedited prudence review of the results of the Track B solicitation and
18 assure both buyers and sellers of full and timely cost recovery.

19 APS has attempted and is attempting to address the concerns of Staff as to affiliate
20 communications and affiliate relations materially affecting Track B. It has pledged to do
21 what it reasonably can to alleviate those concerns, but APS will not promise the
22 impossible and will not compromise the interests of consumers in a counterproductive
23 effort to address every hypothetical concern.

24 APS has successfully managed market risk and market volatility for the benefit of
25 its customers. To continue to do so, it must have the maximum degree of flexibility in the
26

1 procurement of power, including the right to say "no," both in Track B and in secondary
2 procurements outside Track B.

3 APS and Staff are likewise working together to study RMR issues in Phoenix and
4 Yuma. This analysis will determine the scope of the RMR issue, its possible remedies,
5 and the additional costs of such potential remedies. APS also will utilize this study to
6 determine the Company's unmet RMR needs from non-APS resources, which it will
7 solicit as a separate but concurrent part of Track B.

8 Finally, the important issues of DSM, EPS and "environmental risk management"
9 should be studied carefully before the Commission considers any substantive action. In
10 some instances, such studies are already under way, while others could be made the
11 subject of upcoming Commission-sponsored workshops.

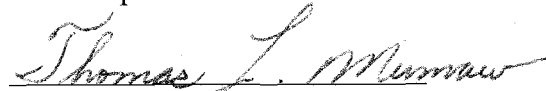
12 RESPECTFULLY SUBMITTED this 18th day of December 2002.

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APPENDIX A

Fitch Ratings

Fitch
Info
Center
Press
Release

Fitch Comments On Staff Testimony In APS Financing Request Ratings

17 Dec 2002 2:05 PM

Fitch Ratings-New York-December 17, 2002: Recent testimony filed by the staff of the Arizona Corporation Commission (ACC) supporting Arizona Public Service Company's (APS) requested financing order is positive for the credit quality of Pinnacle West Capital Corp. (PNW), according to Fitch Ratings. The financing order seeks authority to issue \$500 million of unsecured debt. Proceeds would be used to refinance maturing parent company debt incurred to fund power plant development at its non-regulated subsidiary Pinnacle West Energy Corp. (PWEC). If ultimately approved by the ACC, the financing would provide sufficient liquidity for PNW to meet debt maturities in 2003. In combination with the 'Principles of Resolution' agreed to by the Staff and APS (and discussed below), the staff testimony also lends some clarity to the regulatory process in Arizona and signals a reasonable working environment with the ACC Staff. Fitch recently placed the 'BBB' senior unsecured debt ratings of PNW on Rating Watch Negative citing concern over the company's ability to refinance \$790 million of maturing over the next 14 months, increasing exposure to merchant energy markets, and the uncertain regulatory treatment of 1,800 mw of new generation. The Rating Watch Negative at PNW could be resolved favorably if the financing order were approved by the ACC in combination with a demonstration by the company of access to capital markets at reasonable rates. The transfer of PWEC capacity to APS and its inclusion in rates would also be favorable.

The impact of the staff recommendation on APS' ratings (listed below) will depend on the ultimate treatment of the 1,800 mw of capacity currently owned by PWEC. The current Negative Rating Watch for APS reflects the potential increase in leverage related to PNW's plan to issue debt at APS and regulatory uncertainty over the company's upcoming rate case and the process for securing future power supply. In revising the Rating Watch for APS to Negative from Stable on Dec. 4, 2002, Fitch noted that increased utility debt would be less of a concern if it is part of the cost of acquiring and ultimately rate basing the 1,800 mW's of PWEC generating capacity.

On Friday, Dec. 13, 2002, the ACC Staff filed testimony supporting APS's request for authorization to issue \$500 million of unsecured debt, with the intent to use the proceeds to repay maturing PNW debt. Separately, the Staff and APS have agreed to principles for resolving certain issues raised by APS in its appeal of the Commission's Track A order. Under the resolution, APS would limit any prospective Track A appeal to the following issues, which would be appropriate for consideration by the commission in the company's 2003 base rate case: 1) the inclusion of 1,800 mW's of generation constructed by PWEC to meet APS demand growth; 2) the appropriate treatment of \$234 million of pre-tax asset write-off agreed to by APS as part of the 1999 settlement agreement; and 3) the appropriate treatment for costs incurred by APS in preparation for the transfer of generation assets to PWEC.

PNW's original plan to issue debt at PWEC is no longer possible due to the ACC's decision to block the transfer of APS' generating capacity to PWEC. Also affecting PNW's refinancing plan are depressed wholesale power markets, a restrictive capital market environment, and PWEC's relatively small generation portfolio (1,300 mW's in operation). The planned asset transfer was in accordance with the ACC-approved electric industry restructuring settlement. The ACC's decision in Track A of its generic review of electric competition blocked the transfer of the generation assets from APS to PWEC, and was silent on the status of 1,800 mW's of unregulated generation capacity built by PWEC to meet APS demand growth.

Pinnacle West Capital's ratings are as follows:

--Senior unsecured 'BBB'; and,

--Commercial paper 'F2'.

Arizona Public Service Company's ratings are as follows:

- Senior secured 'A-';
- Senior unsecured 'BBB+'; and,
- Commercial paper 'F2'.

All of APS and PNW's debt securities are on Rating Watch Negative, with the exception of APS commercial paper, which has a Stable Outlook.

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